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May 1, 2017

VIA ELECTRONIC DELIVERY

Honorable Kathleen H. Burgess
Secretary
New York State Public Service Commission
Three Empire State Plaza, 19th Floor
Albany, New York 12223-1350

RE: Case 15-E-0751 – In the Matter of the Value of Distributed Energy Resources

Case 15-E-0082 – Proceeding on Motion of the Commission as to the Policies, Requirements and Conditions for Implementing a Community Net Metering Program

IMPLEMENTATION PROPOSAL FOR THE VALUE STACK COMPONENT OF VDER PHASE ONE TARIFF

Dear Secretary Burgess:

Niagara Mohawk Power Corporation d/b/a National Grid ("National Grid") hereby submits for filing its Implementation Proposal for the Value Stack component of the VDER Phase One tariff in accordance with Ordering Clause No. 14 of the Commission's March 9, 2017 *Order on Net Energy Metering Transition, Phase One Value of Distributed Energy Resources, and Related Matters* in Cases 15-E-0751 and 15-E-0082.

Please direct any questions regarding this filing to:

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Thank you.

Respectfully submitted,

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STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

In the Matter of the Value of Distributed Energy Resources	)	Case 15-E-0751
Proceeding on Motion of the Commission as to the Policies, Requirements and Conditions for Implementing a Community Net Metering Program	)	Case 15-E-0082

IMPLEMENTATION PROPOSAL OF NIAGARA MOHAWK POWER CORPORATION d/b/a NATIONAL GRID FOR THE VALUE STACK COMPONENT OF VDER PHASE ONE TARIFF

In compliance with Ordering Clause No. 14 in the New York State Public Service Commission's ("Commission") *Order on Net Energy Metering Transition, Phase One of Value of Distributed Energy Resources, and Related Matters* ("VDER Order"),[1] Niagara Mohawk Power Corporation d/b/a National Grid ("National Grid" or the "Company") submits this Implementation Proposal. This filing describes how the Company intends to implement the Value Stack of VDER Phase One in the course of the transition to more accurate valuation and compensation mechanisms for Distributed Energy Resources ("DER") that will more appropriately "reflect and properly reward DER's actual value to the electric system and that ensure all customers pay their fair share for the costs of grid operation and benefit from the value they provide."[2]

[1] Case 15-E-0751 *et al.*, *In the Matter of the Value of Distributed Energy Resources et al*. ("VDER Proceeding"), Order on Net Energy Metering Transition, Phase One of Value of Distributed Energy Resources, and Related Matters (issued March 9, 2017) ("VDER Order"), p. 155.
[2] *Id*., p. 3.

I. INTRODUCTION

The VDER Order requires each utility to file an Implementation Proposal for public review and comment, followed by Commission consideration, which includes, at a minimum, the following elements:

1. Calculation and compensation methodologies for Demand Reduction Value ("DRV");
2. Identification of, compensation for, and MW caps for Locational System Relief Value ("LSRV") zones;
3. Proposed methods and values for providing Capacity Values using Alternative 1 and Alternative 2;
4. Identification of average generation profiles for capacity and DRV compensation in projects' first year of operation;
5. Cost allocation and recovery methodologies implementing the principles adopted in the VDER Order for each component of the Value Stack, with particular attention to issues associated with capacity compensation;
6. The practicality of allocating and collecting costs associated with DER compensated under Phase One Net Energy Metering ("NEM") using the principles adopted in the VDER Order;
7. Proposed accounting transactions and ratemaking treatment related to the implementation of the VDER Order;
8. Utility processes for managing billing and tracking bill credits;
9. Reporting procedures for tracking progress in Tranches and any other necessary reporting; and
10. Draft tariffs stating that Market Transition Charge ("MTC") for the residential and small commercial classes, for each tranche, as described in the VDER Order to include rules on how the MTC, DRV, and LSRV will be applied to Community Distributed Generation ("CDG") projects.[3]

The sections that follow in National Grid's Implementation Proposal address each of the above required elements.

[3] *Id.*, p. 136.

II. PROPOSED DRV, LSRV, AND CAPACITY VALUES

In this section National Grid addresses the calculation and proposed compensation values for DRV, LSRV, and Capacity Values in response to Elements 1-3 of the Implementation Proposal requirements.

A. Calculation Methodologies for DRV and LSRV

As directed in the VDER Order, National Grid proposes to calculate two values to compensate eligible projects for demand reduction by "de-averaging" the marginal cost of service ("MCOS") used in the Company's Dynamic Load Management ("DLM") tariff.[4] These two values are the Demand Reduction Value ("DRV") which would apply across the Company's service territory and the Locational System Relief Value ("LSRV") which would apply only to DER projects located in high value areas of the Company's service territory for a limited amount of DER capacity. The LSRV will be additive compensation to the DRV for eligible DER projects.

National Grid proposes an algebraic methodology for "de-averaging" the MCOS to calculate the DRV and LSRV which relies on an estimated percentage of the load in LSVR areas and DRV areas. The Company proposes to implement an LSRV that is set to 50 percent of its DRV, thereby establishing the combined compensation (*i.e.*, LSRV and DRV) received by LSRV-eligible projects as being equal to 150 percent of the DRV. The DRV is derived as follows:

(% of System Load in LSRV Areas x 1.5 DRV) + (1 - % of System Load in LSRV Areas x DRV) = System Average MCOS

[4] Case 15-E-0189 *et al.*, *Petition by Niagara Mohawk Power Corporation to Effectuate Dynamic Load Management Programs et al.*, Tariff Filings of Niagara Mohawk Power Corporation d/b/a National Grid to Effectuate Dynamic Load Management Programs (filed December 1, 2016), Attachment C, p. 3, line 5.

The methodology used for identifying LSRV areas is described below in Section II.B. National Grid has identified 53 LSRV areas at the substation level representing 16.4 percent of the Company's total system load. As the system average MCOS calculated for the Company's most recent DLM tariff is $66.48 per kW-year,[5] solving for DRV in the above equation establishes a proposed initial DRV rate of $61.44 per kW-year. With the LSRV set at 50% of the DRV, this establishes a proposed initial LSRV rate of $30.72 per kW-year. The Company proposes to update its DRV and LSRV rates for use in VDER Phase One every three years as required by the VDER Order. National Grid is in the process of developing a methodology for more granular, locational MCOS values as outlined in its *Work Plan and Timeline to Determine Location Value of Distributed Energy Resources* filed with the Commission on April 24, 2017 in the VDER Proceeding.

B. LSRV Areas and MW Caps

National Grid proposes to identify LSRV areas at the substation level. The Company has identified the areas served by 53 specific substations as LSRV areas for compensation under the VDER Phase One Value Stack tariff. These LSRV areas represent approximately 16.4 percent of the Company's total system load.

To identify its proposed LSRV areas, National Grid scaled loads on all distribution substations in its service territory out to the year 2020 using a peak load forecast that excluded the impacts of future DER generation. Each substation was screened against applicable planning ratings to identify potential loadings above those ratings. Of the 574 substations analyzed, 62 substations were identified as having the potential to exceed their planning rating by 2020. However, as five of these substations have projects underway, or starting within the year, these locations were removed from consideration for LSRV as future DER would not have the

[5] *Id*.

potential to defer the infrastructure investment. Further, four other substations were removed from consideration for LSRV for the reason that the associated MW caps, set according to the criteria described below, would be less than 0.1 MW. Although identified LSRV areas may also be undergoing assessment for non-wires alternative ("NWA") potential, the Company did not exclude these areas as DER has not yet been procured to progress any specific NWA solutions in these areas.

As required by the VDER Order, National Grid has identified MW caps limiting the amount of DER capacity that may receive LSRV compensation at each LSRV area.[6] The MW cap for each selected LSRV substation was determined to be the lesser of the load reduction necessary to reduce peak loading to 100 percent of the planning rating or DER penetration equal to substation minimum load levels, which are assumed to be 25 percent of the forecasted peak loading.[7] The 25 percent of peak load limit was adopted to alleviate concerns about reverse power in a light load scenario.

The sum of MW caps in the 53 selected LSRV areas is equal to 103 MW. It is important to note that the definition of a MW cap for LSRV does not imply that there is sufficient hosting capacity throughout the LSRV area to achieve that cap without distribution system enhancements associated with the interconnection. Hosting capacity may also vary by location on the circuit/feeder. LSRV MW caps may need to be subsequently adjusted if National Grid procures load relief in an LSRV area through a NWA solution, or due to changes in load forecasts or

[6] VDER Order, p. 118.

[7] This reflects a change from the preliminary methodology for identifying LSRV MW caps presented by National Grid at the VDER Technical Conference held on April 5 and April 6, 2017 where the Company proposed that MW caps be based on the lesser of the load reduction necessary to reduce peak loading to 95 percent of the planning rating or DER penetration equal to substation minimum load levels, assumed to be 25 percent of the forecasted peak loading. National Grid subsequently determined that 100 percent of the planning rating better aligns the threshold for identifying LSRV areas and DER MW caps with the Company's planning criteria and provides a more consistent application of LSRV compensation.

system capability. For that reason, actual qualification of a project for LSRV compensation will be determined on a project-by-project basis at the time an interconnection agreement for the project is executed with the Company. Because the provision for LSRV for projects compensated under the VDER Phase One Value Stack and any future NWAs in the same area would seek to relieve the same locational constraints, projects receiving LSRV compensation will have to forego that LSRV compensation if they participate in any future NWA solicitations and are the successful bidder for an NWA, as projects selected for an NWA are ineligible to receive LSRV compensation.

Table 1 below provides the identified LSRV areas at the substation level and their respective MW caps.

Table 1. Identified LSRV Substation Areas and MW Caps

Substation Name	MW Cap
PINE GROVE	13.1
COFFEEN	10.6
HOPKINS	10.1
MENANDS	7.8
WEIBEL AVE.	6.1
PINEBUSH	5.5
HUDSON	5.0
EAST GOLAH	4.8
TEMPLE	3.9
SALISBURY	3.6
REYNOLDS	2.9

BATAVIA	2.4
PETERBORO	2.4
MCKOWNVILLE	2.1
PLEASANT	1.4
BUFFALO STATION 74	1.3
BUFFALO STATION 53	1.3
NEWARK ST.	1.1
LAWRENCE AVE.	1.1
HINSDALE	1.1
CORLISS PARK	1.1
PALOMA	1.0
BUFFALO STATION 32	1.0
BUFFALO STATION 57	1.0
BUFFALO STATION 21	0.9
BOLTON	0.9
SORRELL HILL	0.8
E. PULASKI	0.8
NILES	0.7
ASH STREET	0.5
DUGUID	0.5
BARKER	0.5
BEECH AVE 81	0.5
SOUTHWOOD	0.5
GILBERT MILLS	0.4

SHEPPARD ROAD	0.4
CURRY RD.	0.4
GILMANTOWN RD	0.4
KARNER	0.3
JOHNSTOWN	0.3
BUFFALO STATION 61	0.3
OAKFIELD	0.3
CUBA LAKE	0.2
OGDEN BROOK	0.2
LORDS HILL	0.2
HANCOCK	0.1
KNIGHTS CREEK	0.1
LANSINGBURGH	0.1
SPRINGFIELD	0.1
MEXICO	0.1
NORTH EDEN	0.1
WETHERSFIELD	0.1
WEST ALBION	0.1

Figure 1 below is a map showing the location of each LSRV area. National Grid also proposes to make LSRV area information available to DER providers through its System Data Portal once the Commission approves the Company's LSRV proposal.

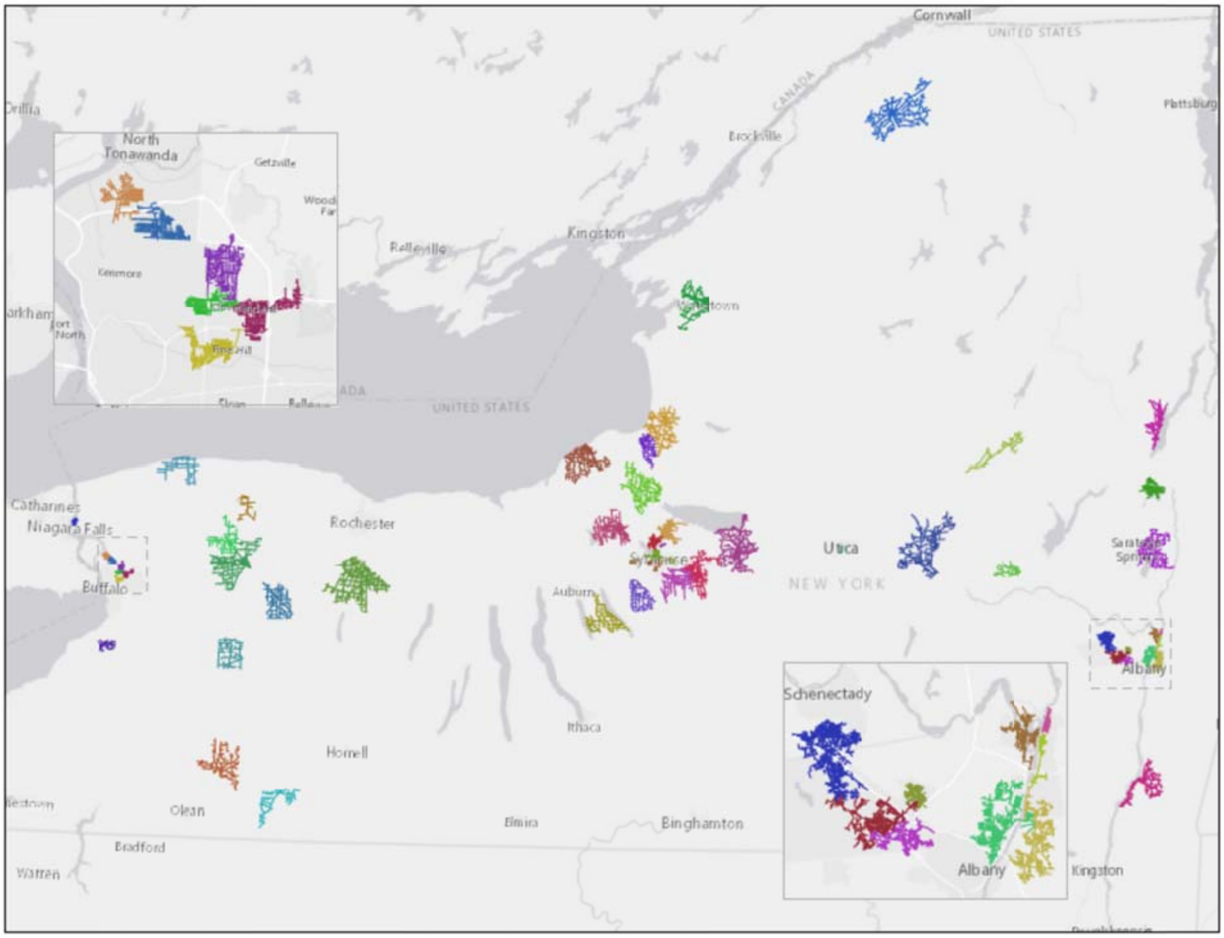

Figure 1. Map of Identified LSRV Areas[8]

C. Compensation Methodologies for DRV and LSRV

As directed by the VDER Order, National Grid proposes to distribute the calculated DRV and LSRV compensation in dollars per kW-year across the ten highest usage hours in the Company's service territory.[9] Compensation for the DRV and, if applicable, the LSRV, would be in the form of a monthly lump sum in the current calendar year based on the DER project's

[8] The color coding on Figure 1 is used to differentiate the boundaries of each LSRV area. As the National Grid distribution system is a radial design, DER projects must interconnect to the circuits/feeders of the identified LSRV substation to provide the corresponding locational benefit.

[9] VDER Order, pp. 117-118. As MCOS values are developed to offer more granular locational compensation, the top ten hours chosen will be based on the local peak to the extent possible and appropriate.

kW performance during those top ten load hours in the previous calendar year. In a project's first year, it would receive DRV and, if applicable, LSRV compensation based on an average generation profile for a project of its technology and rated capacity in the Company's service territory.[10] The average generation profiles to be used to calculate DRV and LSRV compensation are identified in Section III below.

National Grid proposes to identify its top ten load hours and coincident DER performance for the preceding twelve (12) months ending October 31. The monthly compensation paid to each eligible project in the next twelve (12) monthly billing cycles, beginning with the January bill, will be calculated as the DRV and/or the LSRV in dollars per kW-year divided by ten (10) performance hours per year, multiplied by the sum of the project's kW output in the ten performance hours, divided by twelve (12) months.

Any community distributed generation ("CDG") project receiving compensation under the VDER Phase One Value Stack tariff will not receive DRV compensation for the portion of its project that receives a market transition credit ("MTC").[11] A CDG project that is located in a LSRV area will receive LSRV compensation for both the portion of the project that receives the MTC and the portion not eligible for the MTC that receives the DRV.[12] The application of DRV and LSRV values to CDG projects with a mix of both mass market and demand-billed CDG Satellite accounts is further described in the proposed VDER Phase One Value Stack tariff language in attached Appendix A. Appendix A also addresses how the MTC is applied to CDG projects.

Consistent with the VDER Order, the DRV compensation received by an eligible project will not be fixed, but instead will change as the DRV is updated by the Company every three

[10] *Id.*, p. 108.
[11] *Id.*, p. 118.
[12] *Id.*

years.[13] LSRV compensation, if applicable to the project, will be fixed for a period of ten years.[14] Following the ten-year period, the LSRV will be reset to the then applicable LSRV at that location, if any.

D. Capacity Values Using Alternative 1 and Alternative 2

i. Capacity Values Using Alternative 1

As established in the VDER Order, Alternative 1 Capacity Value compensation will be the default compensation value for intermittent technologies.[15] Consistent with the New York State Department of Public Service Staff's ("Staff") recommendation in the VDER Order, National Grid's Alternative 1 Capacity Value will be the capacity portion of the supply charge for the service class with a load profile most similar to a solar generation profile.[16] The solar generation profile relied on to determine the service class supply charge for capacity value is described in Section III below. The service class load profiles used in the evaluation for this purpose are the Company's service class unitized load profiles effective as of May 1, 2017.[17]

"Similarity" between load and generation profiles could be defined on the basis of multiple measures. The Company proposes to select the service class load profile most similar to the solar generation based primarily on the statistical relationship between each service class's hourly load as a percentage of its annual peak and the hour of the year (numbered 1 through 8760). The results of this test may be supported by further examining the statistical relationship between the service class's hourly load as a percentage of its annual peak and other configurations of the temporal variable, such as hour of the day (numbered 1 through 24) and

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[13] *Id.*
[14] *Id.*
[15] *Id.*, p. 102.
[16] *Id.*, p. 99.
[17] National Grid load profiles by service class, effective May 1, 2017, available at https://www9.nationalgridus.com/niagaramohawk/business/rates/5_load_profile.asp)

month of the year (numbered 1 through 12). Graphical representations of the solar generation profile and service class load profiles can also be visually compared to further support the results.

In order to determine the statistical relationship between the solar generation profile and the hour of the year, National Grid proposes to estimate the hourly solar output as a percentage of its annual peak against the hour of the year as number 1 through 8760 using an ordinary least squares ("OLS") linear regression with the intercept set to zero. The resulting coefficient on the hour of year variable is statistically significant at the 95 percent confidence level and shows the extent to which the solar generation load shape is dependent on the hour of the year. The same regression methodology is repeated, replacing the solar generation profile with the load profile for each service class (hourly load as a percentage of its annual peak), as the independent variable. The resulting coefficients on the hour of the year variable for each service class load profile regression are compared to the coefficient result from the solar generation profile regression. The service class with the regression coefficient closest to that of solar generation profile regression is selected as the service class with the load profile most similar to the solar generation profile.

Based on the service class load profiles currently in effect, the above methodology reveals the service class with the load profile most similar to the solar generation profile described in Section III is Service Classification No. 2 Non Demand ("SC2ND"). The result is the same if the generation and load profiles are regressed against the hour of the day (numbered 1 through 24) and the month of the year (numbered 1 through 12). Visual comparison of graphical representations of the generation and load profiles confirms that the SC2ND profile has the most sharply defined average daily peak period, which is the primary characteristic of the solar generation profile, and the SC2ND peak period more closely aligns with the solar generation peak period than the other service class peak periods. The results of the service class load profile analysis will be included in National Grid's filing of capacity values with the Commission on May 15, 2017. Since service class load profiles may change over time and, as described in Section III below, updated or more accurate solar generation profiles may become available in the future, the Company proposes to reanalyze the service class load profiles each year of the VDER Phase One Value Stack and report the results to the Commission in its annual May 15 capacity value filings.

As described in the VDER Order, Alternative 1 Capacity Value compensation will be based on the capacity portion of the effective monthly per kWh supply charge for the selected service class multiplied by the project's total net hourly kWh injections in the billing month. National Grid's supply charges for each service class are calculated monthly and made available in Supply Service Charge Statements filed with the Commission and posted on the Company's website. Supply statements are filed and provided for use in the Company's billing system three days prior to their effective date. Currently, the Company's Supply Service Charge Statements do not include the capacity portions of its supply charges for the SC2ND and residential service classes separately from the supply charge. Upon implementation of the VDER Phase One Value Stack tariff, the Company will provide the capacity portions of the relevant supply charges as explicit values on its monthly Supply Service Charge Statements.

The price National Grid pays for generation capacity is based on Spot Auction prices for the New York Control Area ("NYCA"). As Spot Auction prices become available only after monthly supply charges must be calculated and filed for the upcoming month, the Monthly Auction price is used as a proxy in supply charge calculations. The Company reconciles the difference between the forecasted capacity price in supply rates (*i.e.*, the Monthly Auction price) with the actual capacity costs incurred *(*based on the Spot Auction price) along with other supply costs in the following month through the Electric Supply Reconciliation Mechanism ("ESRM"). National Grid's May 15, 2017 filing of capacity values as required by the VDER Order[18] will include its most recently available capacity charges for the SC2ND service class.

ii. Capacity Values Using Alternative 2

As required by the VDER Order, National Grid's Alternative 2 Capacity Value compensation will be provided as an option for intermittent technologies.[19] The Alternative 2 Capacity Value for each summer season, defined as the period June 1 through August 30, will be calculated and provided by the Company annually by May 15th of each year and will be based on the prior twelve (12) months of capacity prices for the service class with the load profile most similar to the solar generation profile described in Section III. The Company proposes to sum its historical monthly capacity charges for the prior twelve-month period to determine an annualized value. The annualized value will be divided by 460 peak summer hours to determine a $/kWh compensation value to be applied during the following summer season. The $/kWh compensation value will be credited based on the project's kWh generation in the 460 peak summer hours only. The 460 peak summer hours are defined in the VDER Order as hour beginning 14:00 through the end of the hour beginning 18:00 each day in June, July, and August (2:00 pm to 7:00 pm each day for 92 days).[20]

Eligibility for Alternative 2 Capacity Value is limited to projects with intermittent technology explicitly opting into compensation under Alternative 2. Written requests for Alternative 2 compensation must be received by National Grid before May 1 prior to each

[18] VDER Order, p. 103.
[19] *Id.*, p. 102.
[20] *Id.*, p. 100.

summer season to allow time for processing. An intermittent technology project may also opt into compensation under the "Capacity Tag" compensation approach from either Alternative 1 compensation or Alternative 2 compensation.[21] A project that opts into Alternative 2 compensation may not move back to Alternative 1 compensation; likewise a project that opts into the "Capacity Tag" compensation may not switch to Alternative 1 or Alternative 2 compensation.[22]

The service class with the load profile most similar to the solar generation profile will be the same service class selected for Alternative 1, using the same methodology described in Section II.A above. The Company will provide the calculated $/kWh Alternative 2 capacity value for the upcoming summer each year in its May 15 capacity value filing. The compensation value for the summer of 2017 will be provided in the Company's May 15, 2017 Capacity Value filing for informational purposes only. Alternative 2 capacity value compensation will be available starting in the summer of 2018 as DER providers will not have adequate time to make informed opt-in decisions prior to the start of the 2017 summer season.

III. AVERAGE GENERATION PROFILES FOR CAPACITY AND DRV COMPENSATION

In this section National Grid addresses Element 4 of the Implementation Proposal requirements.

As described in Sections II.A, II.C, and II.D above, average solar generation profiles are required to calculate compensation for DRV and LSRV in a project's first year of operation, as well as to select the applicable service class capacity charge for capacity value compensation. National Grid proposes to rely on the average CDG and rooftop solar generation profiles specific

[21] *Id.*, p. 102.
[22] *Id.*

to the Company's service territory that were used for the Staff Report and Recommendations filed in this proceeding in October 2016.[23] These solar generation profiles were provided by E3 utilizing the National Renewable Energy Laboratory ("NREL") System Advisor Model ("SAM") with typical meteorological year ("TMY") weather data for each utility service territory.[24] National Grid proposes to rely on average system solar generation profiles with the most recently available NREL data for the applicable Value Stack tariff calculations until sufficient solar generation data on actual performance in the Company's service territory can be collected and analyzed.

IV. REGULATORY CONSIDERATIONS

In this section National Grid addressed Elements 5-10 of the Implementation Proposal requirements.

A. Cost Allocations and Recovery Methodologies

The following general cost allocation and recovery principles are adopted in the VDER Order:

> Costs associated with compensation under the VDER Phase One tariff will be collected, proportionately, from the same group of customers who benefit from the savings associated with the compensated DER. For compensation that does not reflect a value that has been identified and calculated at this time, recovery will come from customers within the same service class as the beneficiaries.[25]

[23] VDER Proceeding, Staff Report and Recommendations in the Value of Distributed Energy Resources Proceeding, (filed October 27, 2016).
[24] *See* National Renewable Energy Laboratory ("NREL"), System Advisor Model ("SAM"), available at https://sam.nrel.gov/
[25] VDER Order, p. 17.

Accordingly, National Grid proposes the following cost allocation and recovery methodologies for each component of the Value Stack.

1. Energy Value – Energy Value credits are based on the New York Independent System Operator ("NYISO") Day Ahead zonal LBMP hourly prices as adjusted for losses applicable to the project, applied to the project's net hourly injections. Projects are compensated for this Energy component because project exports offset energy purchases the utility would otherwise purchase from the NYISO market. Energy Value credits will be collected from the Company's supply customers as these customers benefit from the avoided purchased power cost. National Grid proposes to recover this value through the ESRM which is how the Company reconciles supply costs.
2. Capacity Value – Projects are compensated for capacity because if not for their generation at the time of the NYISO peak, the New York Control Area ("NYCA") Peak Load Forecast would be higher and more capacity would need to be purchased by all load serving entities ("LSEs"). However, because the Alternative 1 and Alternative 2 Capacity Values are not dependent on the project's performance at the time of the NYISO peak, some portion of capacity costs will not be avoided by project generation. Therefore, the cost recovery must be separated into two parts to accurately reflect costs to be recovered. Recovery will vary based on the best estimate of avoided capacity costs ("Market Capacity Value") and the portion of Capacity compensation that is above avoided capacity costs ("Above Market Capacity Value").

a. Market Capacity Value – this value will be determined by multiplying: i) the net injections from all Value Stack generators that occurred on the peak hour of the Company's system during the previous calendar year, by the average price for capacity for the previous calendar year using NYISO Spot Auction capacity prices. The Market Capacity Value costs will be recovered from all delivery customers through a per kW surcharge for demand customers (including NYPA load) and a per kWh surcharge for non-demand customers. Costs will be allocated among service classes based on the transmission coincident peak allocator (*i.e.*, 1CP).

b. Above Market Capacity Value – This value will be calculated as the difference between the Market Capacity Value costs calculated above and the total capacity credits paid to projects receiving Value Stack compensation. Above Market Capacity Value costs will be collected from all delivery customers within the same service class as the customer receiving the capacity credit. This will be recovered on a per kW basis for demand customers and a per kWh basis for non-demand customers.

3. Environmental Value -- Environmental credits will be based on the higher of the latest Tier 1 Renewable Energy Certificate ("REC") price published by the New York State Energy Research and Development Authority ("NYSERDA") or the net social cost of carbon ("SCC")[26] per kWh applied to the volumetric net hourly injections (unless the customer/project host elects to keep the RECs created by the project). The Environmental Value will be fixed for the term of the compensation for all Value

[26] *Id*., p. 106, note 42, where the SCC is net of the expected Regional Greenhouse Gas Initiative ("RGGI") allowance values as calculated by Staff per the BCA Framework Order.

Stack-eligible projects per the VDER Order. As this compensation is fixed for the term of the project, cost recovery will be separated into a market value and an above market value because the current REC price may differ from the price initially set for the term of the project. Since all default supply customers receive the benefit of a reduction to the utility's REC obligation, the avoided REC costs based on the market value of RECs ("Environmental – Market Value"), will be collected from all default supply customers. The market value of RECs will be collected through the annual Clean Energy Supply Surcharge ("CESS") on a per kWh basis which is the mechanism currently used for cost recovery of REC costs incurred by the Company. Any difference in the market price for RECs and the Environmental credits paid to projects ("Environmental - Above Market Value"), in a given year, will be collected from customers within the same service class as the customer receiving the Environmental credit. This will be recovered from all delivery customers on a per kW basis for demand customers and a per kWh basis for non-demand customers.

4. DRV and LSRV – Costs for the DRV and LSRV which are paid to projects compensated under the Value Stack will be collected from all delivery customers on a voltage delivery level basis and allocated to service classes based on the proportion of customers in each service class receiving the DRV or LSRV, respectively. Costs will be recovered on a per kW basis for demand customers and a per kWh basis for non-demand customers.
5. MTC – As application of the MTC is limited to the portion of a CDG project allocated to mass market customers, the MTC will be recovered from all mass market delivery customers on a per kWh basis. Costs will be allocated to each mass market

class based on the amount of MTC provided to the respective service class in the previous year.

B. Practicality of Allocating and Collecting Costs Associated with DER Compensation under Phase One NEM

Phase One NEM credits will be calculated in a significantly different way than the Value Stack compensation methodology. A key difference lies in the hourly metering of net injections that is associated with the Value Stack methodology, whereas Phase One NEM relies only on a customer's retail net metered load to determine credits. In light of this significant difference, adopting the allocation and cost principles of the Value Stack does not make sense for Phase One NEM. National Grid proposes to allocate and collect costs associated with Phase One NEM based on the principles and practices currently employed under NEM, which is through the Company's Revenue Decoupling Mechanism ("RDM").

C. Proposed Accounting Transactions and Ratemaking Treatment

Attached Appendix B provides National Grid's proposed FERC accounting treatment related to Value Stack compensation components. Ratemaking treatment has been discussed previously under Section IV.A.

D. Processes for Managing Billing and Tracking Bill Credits

i. Billing Processes

National Grid currently bills retail customers using the Customer Service System ("CSS"). Bill credits for NEM customers, remote net metered ("RNM") customers, and CDG Host and CDG Satellite accounts (*i.e.*, CDG project subscribers) are calculated outside of CSS in spreadsheets and the resulting bill credits are posted to customer bills manually in CSS. Posting the bill credits in CSS is a necessary step to assign costs to the appropriate accounting ledgers.

Following the issue of the Commission's CDG Order,[27] the Company initiated a billing project to automate the calculation of bill credits and inclusion on customers' bills for NEM, RNM, and CDG Host and CDG Satellite accounts based on the rules as currently captured in National Grid's P.S.C. No. 220 Electricity (the "Tariff"). This automation effort is a significant undertaking with a projected one-year timeline to complete and the effort is in progress.

As the number of accounts currently associated with NEM and RNM are significant from the perspective of manually performing bill credit calculations, as well as the anticipated growth of CDG projects, National Grid will look to automate the Value Stack compensation components to the extent feasible. This automation effort cannot be initiated until the Commission considers and acts on this Implementation Proposal and corresponding tariff leaves. Once initiated, this automation effort is expected to take up to one year to complete, at a minimum. Any projects compensated under the Value Stack tariff prior to the completion of this automation effort will have to be billed on a manual basis using spreadsheets with bill credits posted manually in CSS similar to the current approach being utilized for NEM, RNM, and CDG Host and CDG Satellite accounts under the current tariff provisions.

Furthermore, National Grid currently calculates retail hourly LBMP prices for customer supply charges outside of CSS in a program referred to as the Pricing Transmission System ("PTS"). PTS performs the hourly price calculations on a daily basis for the next day's billing and automatically feeds these prices to CSS for billing. It is expected that PTS will need to be modified to calculate day-ahead LBMP prices for the Value Stack LBMP calculation as current calculations include capacity costs. Any modifications would be done in parallel and integrated with the overall billing project as described above for the Value Stack tariff.

[27] Case 15-E-0082, *Proceeding on Motion of the Commission as to the Policies, Requirements and Conditions for Implementing a Community Net Metering Program*, Order Establishing a Community Distributed Generation Program and Making Other Findings (issued July 17, 2015)("CDG Order").

The Company will be developing detailed estimates for the timeline and costs to automate the above processes, as well as developing manual processes to calculate and post credits until such time as the automation project can be completed.

ii. Value Stack Credit Calculations

The following describes how the compensation components of the Value Stack will be calculated and billed.

a. Energy Value – Energy Value compensation will be calculated by multiplying the project's net hourly injections by the Day Ahead zonal LBMP hourly price, including losses, for the applicable hours.

b. Capacity Value – There are three options for Capacity Values available to the project.

   1. Alternative 1 Capacity Value – Capacity Value compensation will be calculating by multiplying the total project's net injections (kWh) for the billing period by the Alternative 1 Capacity Value ($/kWh) in effect at the time of billing.

   2. Alternative 2 Capacity Value – Capacity Value compensation will be calculated by multiplying the project's net injections (kWh) for each on-peak hour in the summer months of June, July, and August by the effective Alternative 2 Capacity Value ($/kWh) calculated as described in Section II.D above. The on-peak hours will be defined as the hours of 2 pm to 7 pm, each day in June, July, and August.

   3. Capacity Tag Approach – The VDER Order indicates that customers may choose a Capacity Tag Approach for receiving capacity compensation if they

submit a request to the utility.[28] Capacity Tag Approach credits will be calculated by multiplying the project's net injections for the peak hour of the previous calendar year by the applicable capacity rate ($/kw-mo) in effect for each billing period of the current calendar year.

c. Environmental Value – Environmental Value compensation will be calculated by multiplying the project's total net injections (kWh) in the billing period by the Environmental Value ($/kWh) for which the customer-generator is eligible and which is in effect during the billing period.

d. DRV – DRV compensation will be calculated by multiplying i) the average of the project's net injections (in kW) for each of the ten (10) highest peak hours in the Company's service territory during the preceding calendar year, by ii) the DRV ($/kW-mo) in effect during the billing period of the current calendar year, if the customer is eligible to receive DRV compensation. The DRV is further adjusted as applied to CDG projects by the percentage of the project's CDG Satellite accounts' load that is on a demand-billed rate. This is described in more detail in the draft tariff language in Appendix A.

e. LSRV – LSRV compensation will be calculated for by multiplying i) the sum of the project's net injections (in kW) for each of the ten (10) highest peak hours in the Company's service territory during the preceding calendar year, by ii) the LSRV compensation in effect, applicable to the project's location, only if the project is eligible for LSRV compensation.

f. MTC – The MTC rate ($kWh) applicable to the project will be applied to the project's total net injections in a billing period. Only CDG projects are eligible for

[28] VDER Order, p. 102.

the MTC. MTC compensation for CDG projects will apply to the percentage of load that is represented by the CGD project's actual mass market customers. This is described in more detail in the draft tariff language in Appendix A. Additionally, National Grid's worksheets for the calculation of the MTC are being filed in Excel format contemporaneously with the Commission as Appendix C.

E. Reporting Procedures for Tracking Progress in Tranches and Other Required Reporting

The VDER Order requires each utility to provide regular reporting on progress in filling the tranches for CDG projects and explicit notice when 85 percent of the total incremental CDG allocation is reached.[29] For National Grid, the total incremental CDG allocation is 474 MWs[30] with 402.9 MWs triggering the notice requirement. The Company proposes to fulfill the regular reporting requirement by initially posting this information to the National Grid Distributed Generation ("DG") website.[31] By June 2017, National Grid expects to display a real-time dashboard showing the available capacity remaining in each tranche and create additional reports as needed via its new Interconnection Online Application Portal ("IOAP"). The IOAP will eventually supplant National Grid's DG website as the primary source for DG customer information. The Company also proposes to file a formal notice with the Commission on a monthly basis in conjunction with its interconnection inventory reporting per the Standardized Interconnection Requirements ("SIR") as to the remaining capacity as of the end of the preceding month. Should the volume of CDG applications increase, the frequency of the reporting on the

[29] *Id.*, p. 89.
[30] *Id.*, Table 4, p. 131.
[31] Available at http://www.nationalgridus.com/niagaramohawk/home/energyeff/3_distributed.asp

remaining capacity in each tranche will be adjusted accordingly, upon conferring with Staff, to a more frequent interval. National Grid will file a formal notice with the Commission when each tranche is filled as well as when 85 percent of the total incremental CDG allocation is reached.

Additionally, the VDER Order requires each utility to monitor mass market on-site projects under Phase One NEM to ensure that such projects do not create the potential for unreasonable impacts on non-participants. The Commission requires each utility to provide frequent and transparent reporting on the progress under the MW capacity allocation and explicit notice when 85 percent of the allocation is reached so that the Commission may consider appropriate action.[32] For National Grid, the Phase One NEM mass market capacity allocation is 100 MWs which establishes 85 MWs as the notice trigger.[33] The Company proposes to file a formal notice with the Commission on a monthly basis in conjunction with its interconnection inventory reporting per the SIR of the installed capacity of mass market on-site projects interconnected as of the end of the preceding month. Should the need arise, the frequency of the reporting on the installed capacity of mass market projects will be adjusted accordingly, upon conferring with Staff, to a more frequent interval. National Grid will file a formal notice with the Commission when 85 percent of the mass market allocation is reached.

F. Draft Tariff Language

Lastly, the VDER Order requires that the utilities provide draft tariff language that includes rules on the application of the MCT for residential and small commercial class customers who are CDG project subscribers as well as rules on how the DRV and LSRV will be applied to CDG projects.[34] Appendix A provides draft tariff language for the VDER Phase One

[32] VDER Order, p. 86.
[33] *Id.*, Table 3, p. 87.
[34] *Id.*, p. 136.

Value Stack as currently proposed to be implemented including the aforementioned rules relative to CDG projects.

V. CONCLUSION

National Grid appreciates the opportunity to submit this Implementation Plan for consideration and looks forward to working with the New York State Department of Public Service Staff and stakeholders in the transition to the Value Stack framework of VDER Phase One.

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Respectfully submitted,

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APPENDIX A

Appendix A

Niagara Mohawk Power Corporation d/b/a National Grid
Proposed Tariff Language for VDER Phase One Value Stack

40. VALUE OF DISTRIBUTED ENERGY RESOURCES (VDER)

40.1 Phase One NEM

40.2 Value Stack

a. Under VDER Phase One, the Value Stack will only be available for those technologies and projects eligible under NEM per PSL Section 66-j and Section 66-l.

b. Remote net metered, large on-site, and CDG projects which have not met the requirements in Rule No. 40.1.3 to qualify for Phase One NEM will be compensated based on the Value Stack.

c. Remote net metered, large on-site, and CDG projects paired with energy storage will be required to receive compensation based on the Value Stack.

d. The Value Stack will be based on monetary crediting for net hourly injections and eligible technologies and projects will be compensated for net injections into the grid. No compensation beyond the existing benefit of bill reductions through reduced metered consumption will be offered for energy generated and consumed on site until VDER Phase Two. Alternatively, customers can arrange for their generation to be separately metered from their consumption with the additional metering cost to be borne by the customer in accordance with Rule No. 25 – Meter.

e. All projects compensated under the Value Stack must be equipped with interval meters in accordance with Rule No. 25 – Meter, capable of recording net hourly consumption and injection. The customer-generator will be responsible for the cost of such interval meters.

f. Projects eligible for the Value Stack will receive compensation for a term of 25 years from the date of interconnection and will have the ability to carryover excess credits to subsequent billing periods and annual periods as follows:

i. Excluding credits held by CDG project sponsors, unused credits may be carried over to the next monthly billing period, including to the next annual period.

ii. At the end of a project's compensation term, any unused credits will be forfeited.

iii. CDG project sponsors will be given a two-year grace period beyond the end of the annual period to distribute any credits they retain at the end of the annual period.

iv. If at any time during the grace period the CDG project sponsor has credits in its account throughout the grace period, then at the end of the grace period the CDG project sponsor will be required to forfeit a number of credits equal to the smallest number of credits that were in its account at any point during the grace period, since that represents the number of credits that were held over from the previous period.

v. CDG project sponsors will only be permitted to retain credits for distribution during the two-year grace period if those credits remain after the sponsor has distributed as many credits as practicable to members, such that each member's consumption in the final month of the annual period is fully offset by the credits provided.

g. Compensation under the Value Stack for net injections will be calculated based on the values associated with:

i. Energy Value, based on the day-ahead hourly zonal LBMP, inclusive of losses, as used in the MHP tariffs applied to net hourly injections;

ii. Capacity Value, based on retail capacity rates for intermittent technologies as described in Alternative 1, Alternative 2, and the Capacity Tag Approach for dispatchable technologies below:

a. Alternative 1 – Capacity Value compensation will be calculating by multiplying the project's net injections (kWh) for the billing period by the Alternative 1 Capacity Value ($/kWh) in effect at the time of billing. The Alternative 1 Capacity Value will be determined as the capacity portion of the per kWh supply charge applicable to Service Classification No. 2 non demand customers for the applicable billing period.

b. Alternative 2 – Capacity Value compensation will be calculated by multiplying the project's net injections (kWh) for each on-peak hour in the summer months of June, July, and August by the effective Alternative 2 Capacity Value ($/kWh). The Alternative 2 Capacity

Value will be determined as the sum of the historical monthly capacity charges for the previous calendar year divided by 460 peak summer hours to determine a $/kWh compensation value to be applied during the following summer season. The on-peak hours will be defined as the hours of 2 pm to 7 pm each day in the months of June, July, and August.

c. Capacity Tag Approach – determined as the product of i) the generator's kW output during the Company's peak hour in the previous year, and ii) the actual monthly NYISO capacity spot market prices for the applicable billing month.

iii. Environmental Value, based on the higher of the latest CES Tier 1 Renewable Energy Certificate (REC) procurement price published by NYSERDA or the Social Cost of Carbon (SCC), net of the expected Regional Greenhouse Gas Initiative (RGGI) allowance values, as calculated by Staff per the PSC's BCA Framework Order except that:

a. the weighted average price of $0.02424 per kWh from the May 2016 NYSERDA Main Tier solicitation, being higher than the net SCC, shall be used until a subsequent solicitation is conducted and published.

iv. Demand Reduction Value (DRV) and Locational System Relief Value (LSRV) based on de-averaging of utility marginal cost of service (MCOS) studies, will be determined as follows and will subject to the further stipulations specified in a through f below:

a. DRV – DRV compensation will be calculated by multiplying i) the average of the project's net injections (in kW) for each of the ten (10) highest peak hours on the Company's service territory during the preceding calendar year, by ii) the DRV ($/kW-mo) rate in effect during the billing period of the current calendar year, if the customer is eligible to receive the DRV credit. The current DRV rate will be determined every three years. The rate will be updated in a rate statement and will be published three (3) days prior to its effective date. DRV compensation shall be further limited to those CDG projects that do not receive the Market Transition Credit (MTC) as described in Rule 40.3x.

b. LSRV – LSRV compensation will be calculated by multiplying i) the average of the project's net injections (in kW) for each of the ten (10) highest peak hours on the Company's service territory during the preceding calendar year, by ii) the LSRV ($/kW-mo) in effect and applicable to the project's location. The LSRV will be set at 50% of the DRV value for the applicable billing period. The LSRV will be determined every three years. The LSRV will only be available to projects located in LSRV areas. Eligible LSRV areas that have been identified by the Company may be found on the Company's website.

c. For those projects eligible for DRV compensation, the DRV compensation will not be fixed but instead will change as updated by the Company.

d. Any project that receives LSRV compensation shall receive that compensation for a period of ten years, after which time the LSRV will be reset to the then applicable LSRV at that location, if any.

e. LSRVs areas shall have corresponding MW caps to avoid providing compensation without corresponding benefits.

f. CDG projects located in LSRV areas that receive the MTC as described in Rule 40.3x will remain eligible to receive LSRV compensation as described in Rule 40.3x.

40.3 CDG Projects Compensated under the Value Stack

a. CDG projects compensated under the Value Stack will be eligible to receive an MTC. CDG projects will receive a pro-rata MTC for the portion of the CDG project allocated to mass market CDG Satellite accounts but shall not receive a DRV for that portion of the CDG project. Mass market CDG Satellite accounts are associated CDG customer accounts served under a residential or small commercial service class that are not billed for demand who shall own or contract for a portion of the credits in excess of load accumulated at the CDG Host's meter. The portion of the CDG project allocated to mass market CDG Satellite accounts is determined by the sum of the percent allocations of the CDG project assigned to mass market CDG Satellite accounts by the CDG Host as required under Rule No. 29.2 – Requirements of CDG Hosts and Rule 29.3 – Allocation of Generators' Output.

b. Eligibility for MTC compensation is subject to the availability of the CDG market capacity allocation for CDG projects built during VDER Phase One which the PSC has set at 474 MW for the Company. The CDG market capacity allocation is further allocated to three distinct tranches representing declining MTC compensation values. Tranche 0, representing CDG Host facilities compensated under Phase One NEM, combined with Tranche 1, representing the Tranche 0/1 of CDG projects compensated under the Value Stack tariff and eligible for the MTC is limited by the PSC to 119 MW of CDG capacity for the Company. CDG projects in Tranche 0/1 will receive Value Stack compensation plus a per kWh MTC that is equal to 100% of the "Base Retail Rate," minus the "Estimated Value Stack," as defined below, for the portion of the CDG project allocated to mass market CDG Satellite accounts. Once the MW allocation in Tranche 0/1 has been reached, CDG projects will be placed into Tranche 2 and receive a reduced MTC that is equal to 95% of the "Base Retail Rate," minus the "Estimated Value Stack," for the portion of project allocated to mass market CDG Satellite accounts. Tranche 2 is limited by the PSC to 178 MW of CDG capacity for the Company. Once Tranche 2 allocation has been reached, CDG projects will be placed into Tranche 3 and receive a reduced MTC that is equal to 90% of the "Base Retail Rate," minus the "Estimated Value Stack," for the portion of project allocated to mass market CDG Satellite accounts. Tranche 3 is limited by the PSC to 177 MW of CDG capacity for the Company.

c. CDG project eligibility for placement in a tranche will be based on the time-stamp of a 25% advanced payment received from the CDG project sponsor for interconnection upgrade costs or execution of a standard interconnection contract if no such payment is required. If an established tranche allocation has not yet been exhausted but the next eligible CDG project exceeds the MW allocation remaining in that tranche, the CDG project will be eligible to receive the MTC in that tranche for the full capacity of that CDG project. However, the amount of the CDG project's capacity that exceeds the MW capacity remaining in that tranche will count towards fulfillment of the subsequent tranche.

d. For each tranche, two separate per kWh MTCs are applied to (1) the portion of the kWh output of the CDG project that is allocated to residential CDG Satellite accounts and (2) the portion of the kWh output of the CDG project that is allocated to small commercial, non-demand CDG Satellite accounts.

e. For purposes of setting the MTC to be applied to the portion of the CDG project allocated to residential CDG Satellite accounts, the "Base Retail Rate" is defined as the sum of:

i. Volumetric delivery rate for the SC1 service class effective on March 9, 2017; and

ii. Average per kWh System Benefit Charge (SBC) for the SC1 service class for the 36 months in the years 2014, 2014, and 2016, weighted by the monthly kWh produced by the pro forma solar photovoltaic (PV) profiles for a 2 MW system in the Company's service territory, attached as Appendix C to Staff's Report and Recommendations in the Value of Distributed Energy Resources Proceeding in Case 15-E-0751 filed with the PSC on October 27, 2016; and

iii. Average per kWh Merchant Function Charge (MFC) for the SC1 service class for the 36 months in the years 2014, 2014, and 2016, weighted by the monthly kWh produced by the pro forma solar PV profiles for a 2 MW system in the Company's service territory; and

iv. Average portion of the retail commodity charge designed to collect NYISO capacity costs for the SC1 service class for the 36 months in the years 2014, 2014, and 2016, weighted by the monthly kWh produced by the pro forma solar PV profiles for a 2 MW system in the Company's service territory; and

v. Average retail energy charge for the SC1 service class, calculated as the commodity charge minus the capacity portion of the supply charge, for the 36 months in the years 2014, 2014, and 2016, weighted by the monthly kWh produced by the pro forma solar PV profiles for a 2 MW system in the Company's service territory.

f. For purposes of setting the MTC to be applied to the portion of the CDG project allocated to small commercial, non-demand billed CDG Satellite accounts, the "Base Retail Rate" is calculated exactly as it is for the portion allocated to residential CDG Satellite accounts, except that the commercial, non-demand delivery, SBC, MFC, capacity, and commodity charges are used.

g. The "Estimated Value Stack," as calculated for the purposes of setting the MTC only, is calculated as the sum of:

i. The Environmental Value, based on the most recent NYSERDA Main Tier solicitation, set at $0.02424 per kWh; and

ii. The average portion of the retail commodity charge designed to collect NYISO capacity costs for the SC1 service class (for the portion of the project allocated to residential CDG Satellite accounts) or for the small commercial, non-demand billed service class (for the portion of the project allocated to small commercial, non-demand billed CDG Satellite accounts) for the 36 months in the years 2014, 2014, and 2016, weighted by the monthly kWh produced by the pro forma solar PV profiles for a 2 MW system in the Company's service territory; and

iii. The average Day-Ahead LBMP for all hours in the years 2014, 2015, and 2016 weighted by the hourly kWh produced by the pro forma solar PV profiles for a 2 MW system in the Company's service territory.

h. Based on the calculations outlined above, the Tranche 0/1, 2, and 3 MTCs for the portions of the CDG project allocated to residential and small commercial, non-demand billed CDG Satellite accounts are as follows:

Tranche	Residential MTC	Small Commercial, Non-Demand MTC
0/1	\$0.0299	\$0.0377
2	\$0.0246	\$0.0319
3	\$0.0193	\$0.0261

i. CDG projects that receive a pro-rata MTC based on the portion of their CDG project that is allocated to mass market CDG Satellite accounts shall not receive a DRV for that portion of the CDG project. Per kW-month DRV compensation shall be applied as specified under Rule No. 40.2 to the portion of the CDG project that is allocated to demand billed CDG Satellite accounts. CDG projects that receive the MTC will remain eligible for the LSRV given that the LSRV compensates for defined locational values. A per kW-month LSRV adder is applied, as specified under Rule No. 40.2 to the CDG project as a whole.

j. For each CDG project receiving compensation under the Value Stack, a total project monetary credit, based on the project's hourly net injections, is calculated. The total project monetary credit is allocated to CDG Satellite accounts based on the individual account allocations provided by the CDG sponsor as required under Rule No. 29.2 – Requirements of CDG Hosts and Rule 29.3 – Allocation of Generators' Output. Credits will be applied to the CDG Satellite accounts in their next bill according to the billing cycle of the CDG Satellite account.

k. Total CDG project monetary credits are calculated as the sum of:

i. The Value Stack compensation as specified under Rule No. 40.2 for the Energy Value, Capacity Value, Environmental Value, DRV , and LSRV components; and

ii. The tranche-specific residential MTC in dollars per kWh multiplied by the CDG project's net hourly kWh injections, multiplied by the percent of the CDG project allocated to residential CDG Satellite accounts; and

iii. The tranche-specific small commercial, non-demand billed MTC in dollars per kWh, multiplied by the CDG project's net hourly kWh injections multiplied by the percent of the CDG project allocated to small commercial, non-demand billed CDG Satellite accounts.

APPENDIX B

Proposed Accounting Treatment of VDER Components

Value Stack Components	**Customer Credits** Company credits to customers for the acquisiton of the load		**Recovery Revenue** Customer charges		**Deferral Accounting**	
	FERC Acct db	FERC Offset cr	FERC Acct cr	FERC Offset db	Deferral	Offset
Energy	555	142/232	440-444	142	182.3/254	456
Market Capacity Value	555	142/232	440-444	142	182.3/254	456
Above Market Capacity Value	555	142/232	440-444	142	182.3/254	456
Environmental - Market Value	555	142/232	440-444	142	182.3/254	456
Environmental - Above Market Value			440-444	142	182.3/254	456
	588/598		440-444			
Demand Reduction Value (DRV)		142/232		142	182.3/254	456
	588/598		440-444			
Location System Relief value (LSRV)		142/232		142	182.3/254	456
Market Transition Credit (MTC)	908	142/232	440-444	142	182.3/254	456